



CALIFORNIA ISO

California Independent
System Operator

Review of State of the Market for 2002

Report to the Federal Energy Regulatory Commission

April 30, 2003

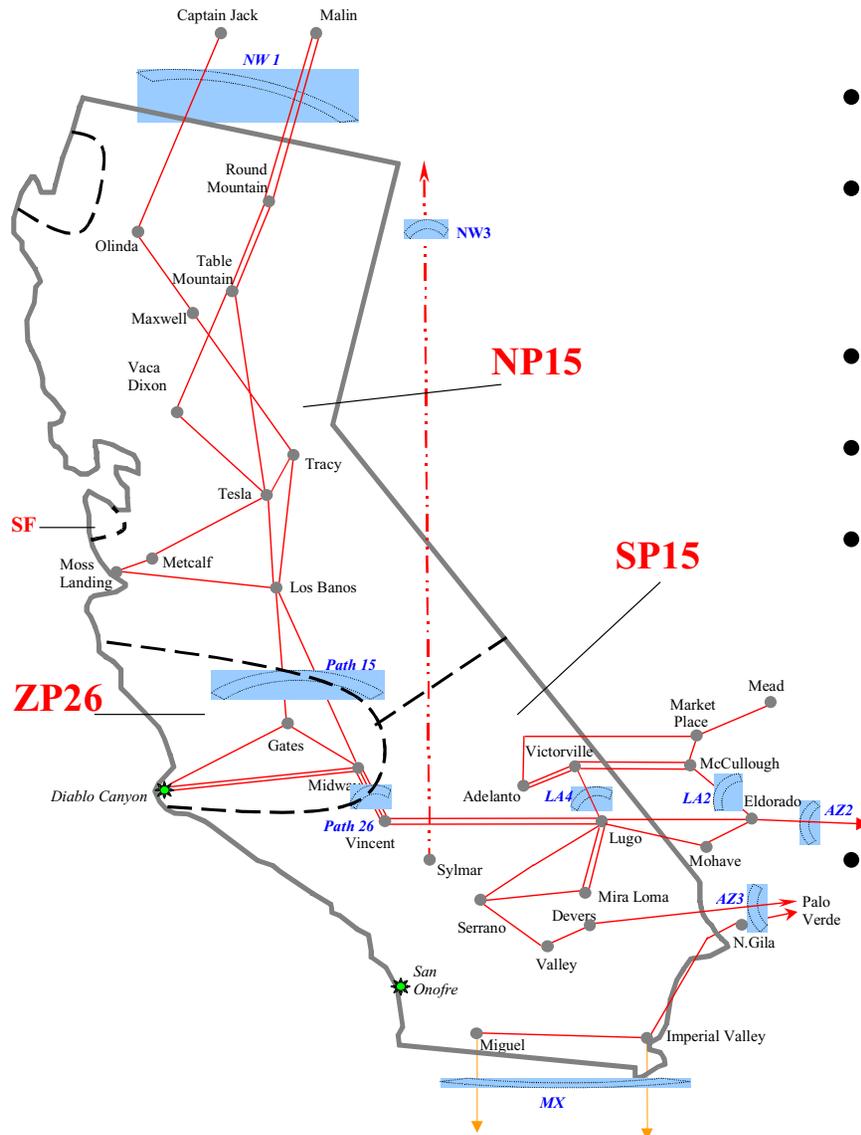
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Overview of Control Area



- 10 million customers served
- 25,000 circuit miles of network transmission
- 42,441 MW peak load
- 232,000 GWh annual energy
- 45,000 MW of installed generation capacity before derates for hydro and outages
- 5,000 MW net imports

*All statistics are for 2002



2002 Market Rule Changes

- Current ISO markets
 - Real Time Imbalance Energy Market (Zonal)
 - Day Ahead and Hour Ahead congestion management
 - Ancillary service mrkts: regulation, spin, non-spin, replacement
 - No Day Ahead energy market, State purchased energy to make up the deficiency in utility generation
- Feb: Zero-bid requirement on import bids in real-time
- April: Imports to be paid instructed energy price
- May: New Automated Dispatch System (ADS)
- October: MD02 Phase IA
 - Soft price cap changed to \$250/MWh from \$91.87/MWh
 - Automated Mitigation Procedures (AMP)



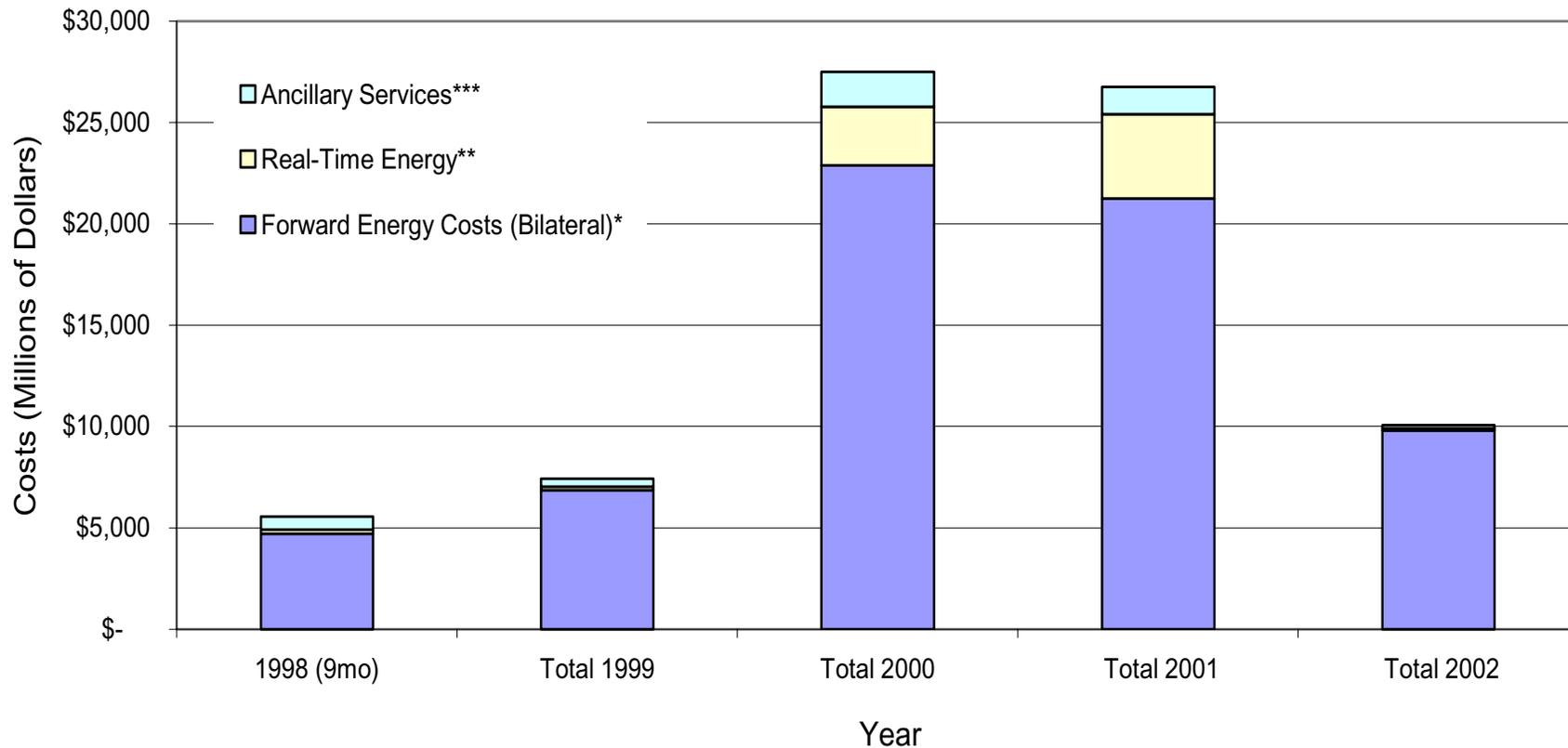
2002 Market Highlights: Market Health and Costs

- Market health vastly improved since 2000-01 crisis due primarily to supply/demand fundamentals
 - Long-term contracts, new generation, significant imported energy all helped to stabilize ISO markets
 - Moderate loads; few demand response programs but being encouraged by new State and ISO initiatives
 - Real-time volumes small, improved accurate forward scheduling
- Most load met by long-term contracts and utility-retained generation. Total market costs just over \$10 billion in 2002 (\$43/MWh), compared to \$27 billion in 2000 and 2001, \$7.4 billion in 1999



Total wholesale electricity costs decreased 62% between 2001 and 2002, Including 95% decrease in real-time and ancillary services costs

Total Wholesale Electricity Costs in ISO Control Area, 1998-2002

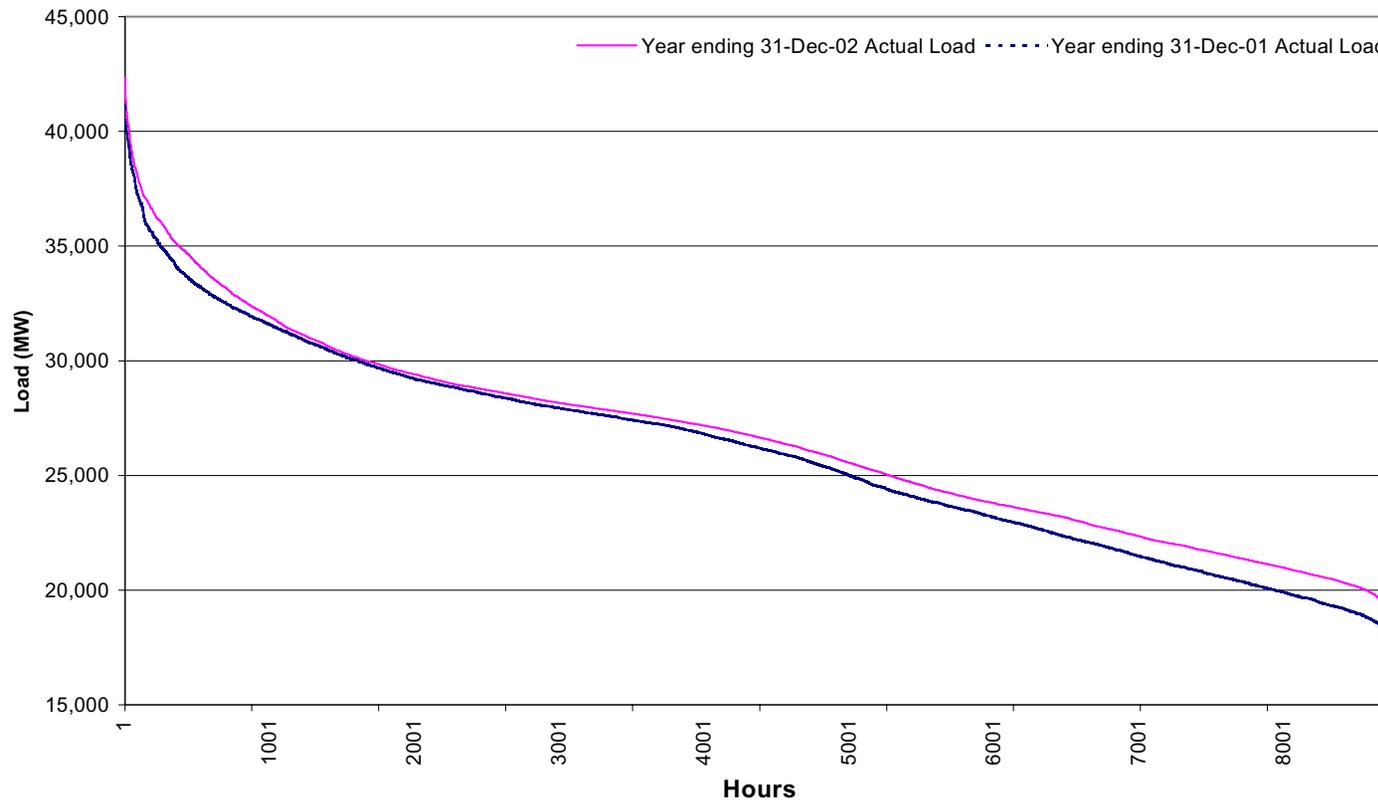




Load Growth in 2002

Total Energy Consumption was up 2% in 2002 due to warmer weather and reduced conservation. Little change in Peak Load.

Load Duration Curve for 2001 and 2002



Note: values are instantaneous top-of-hour actual loads. Intra-hour peaks are not included.



I. Nearly 4,000 MW of generation added since 2001 ***2001-2002 New Generation Additions and Retirements***

<i>Congestion Zone</i>	<i>2001 Generation Additions (MW)</i>	<i>2002 Generation Additions (MW)</i>	<i>2002 Generation Reductions (MW)</i>	<i>Net Generation Change (MW)</i>
NP15	1,550	2,263	-8	3,805
ZP26	338	71	0	409
SP15	685	430	-1,401	-286
ISO Control Area	2,573	2,764	-1,409	3,928

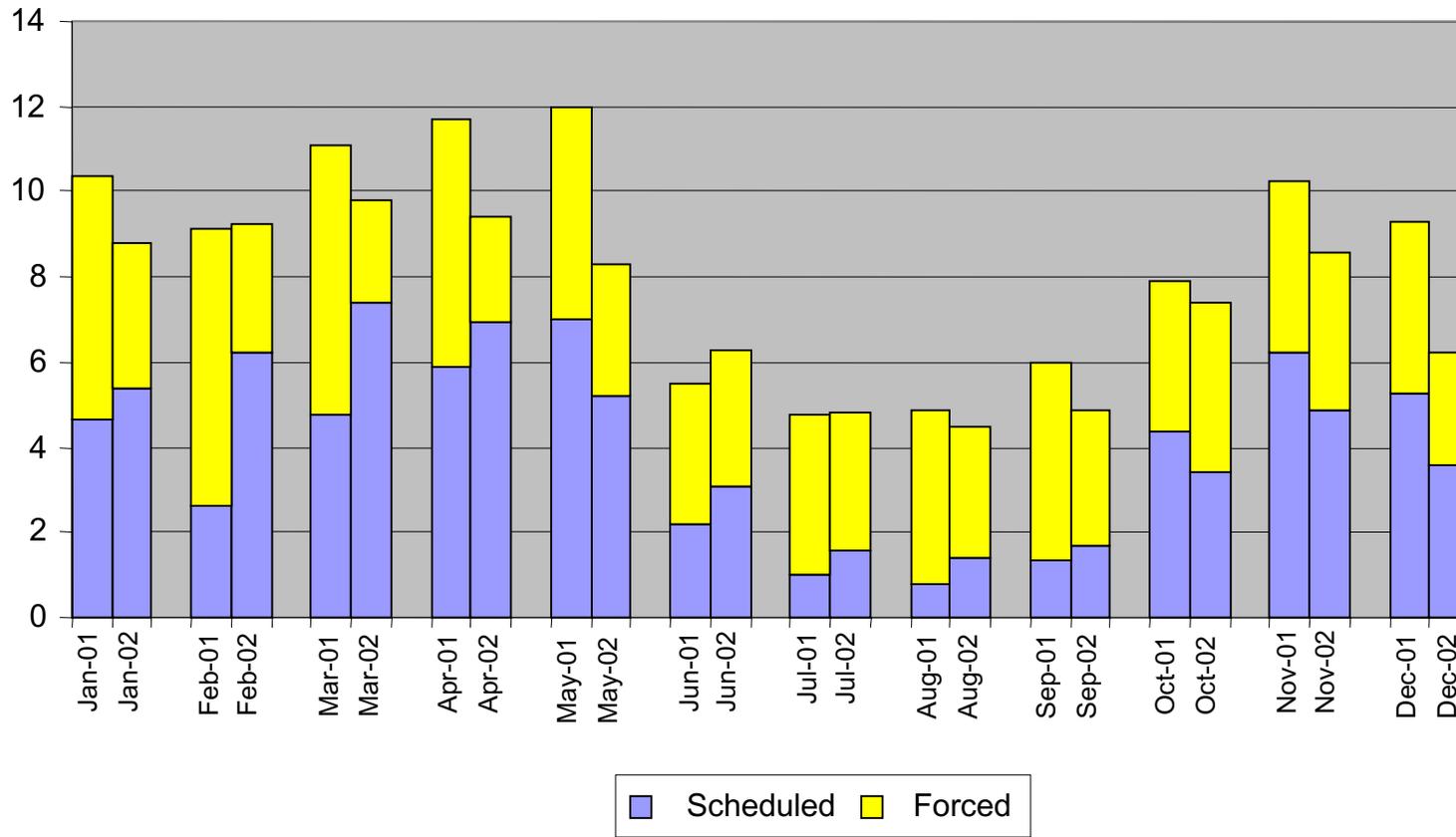
II. Reviewed and approved 22 transmission upgrades worth \$700 million



Improved generation outage co-ordination in 2002 has kept outages below levels in 2001

Average Hourly Outages by Type

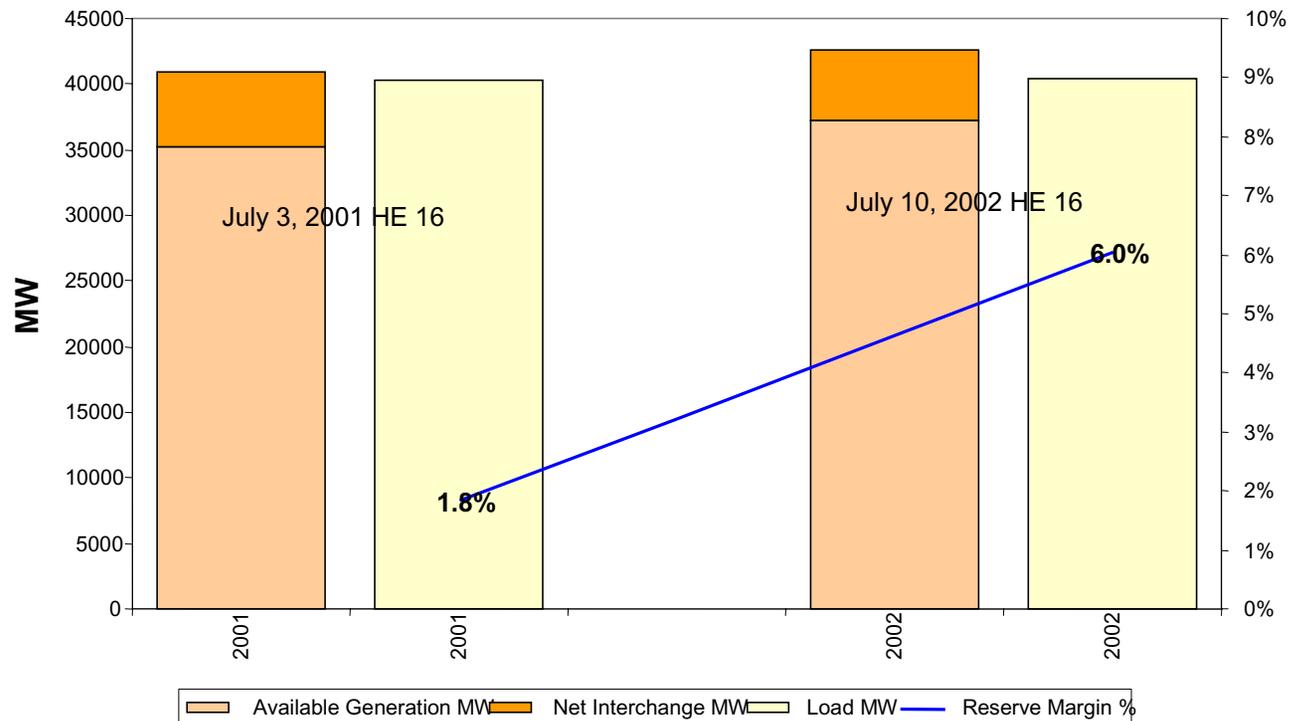
Thousands of MW out





Reserve Margin increased to 6% in peak hour of 2002 from 1.6% in peak hour of 2001

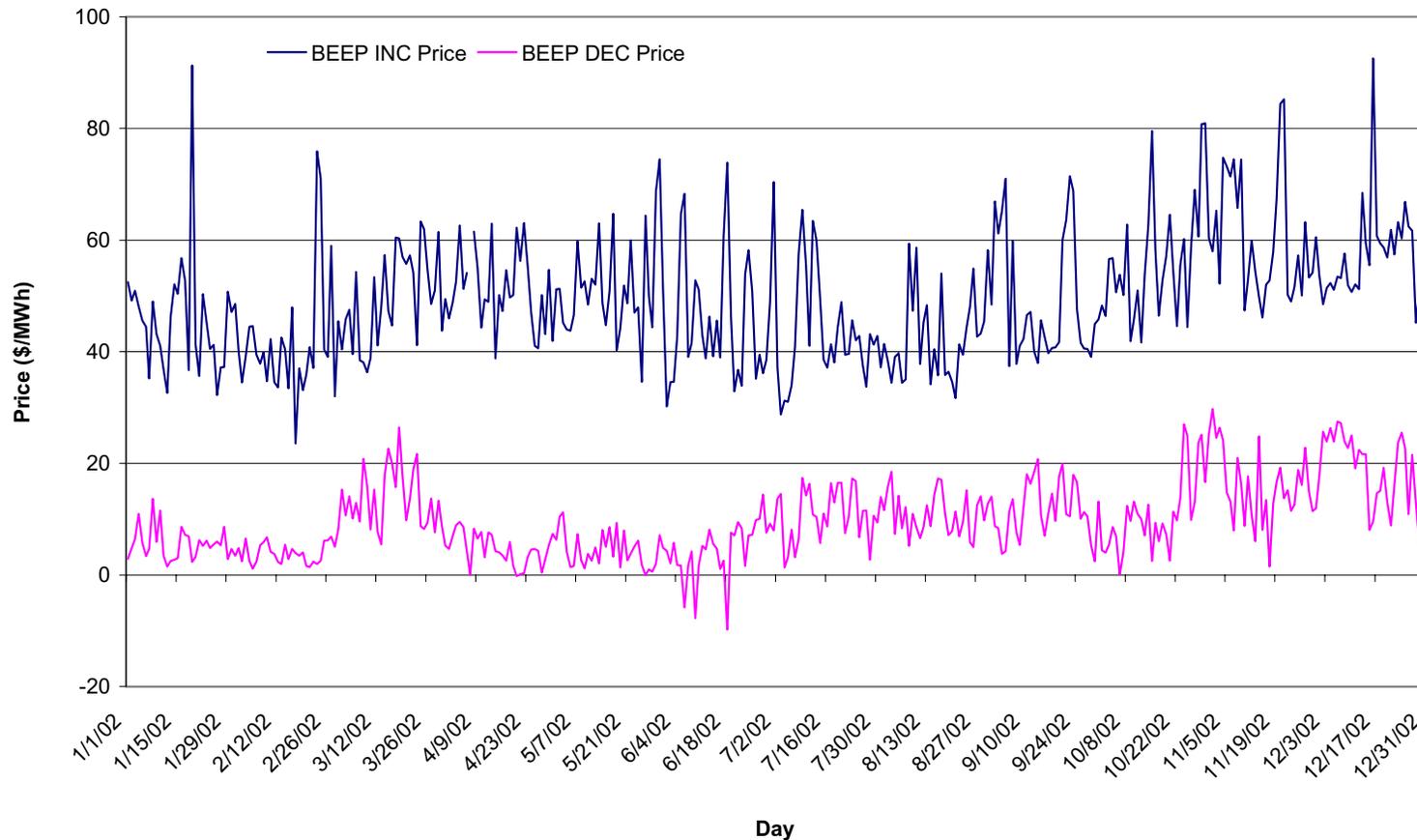
Annual Peak Hour Reserve Margins in 2001 and 2002





Average real-time Incremental dispatch price varied between \$40 and \$60/MWh for most days in 2002

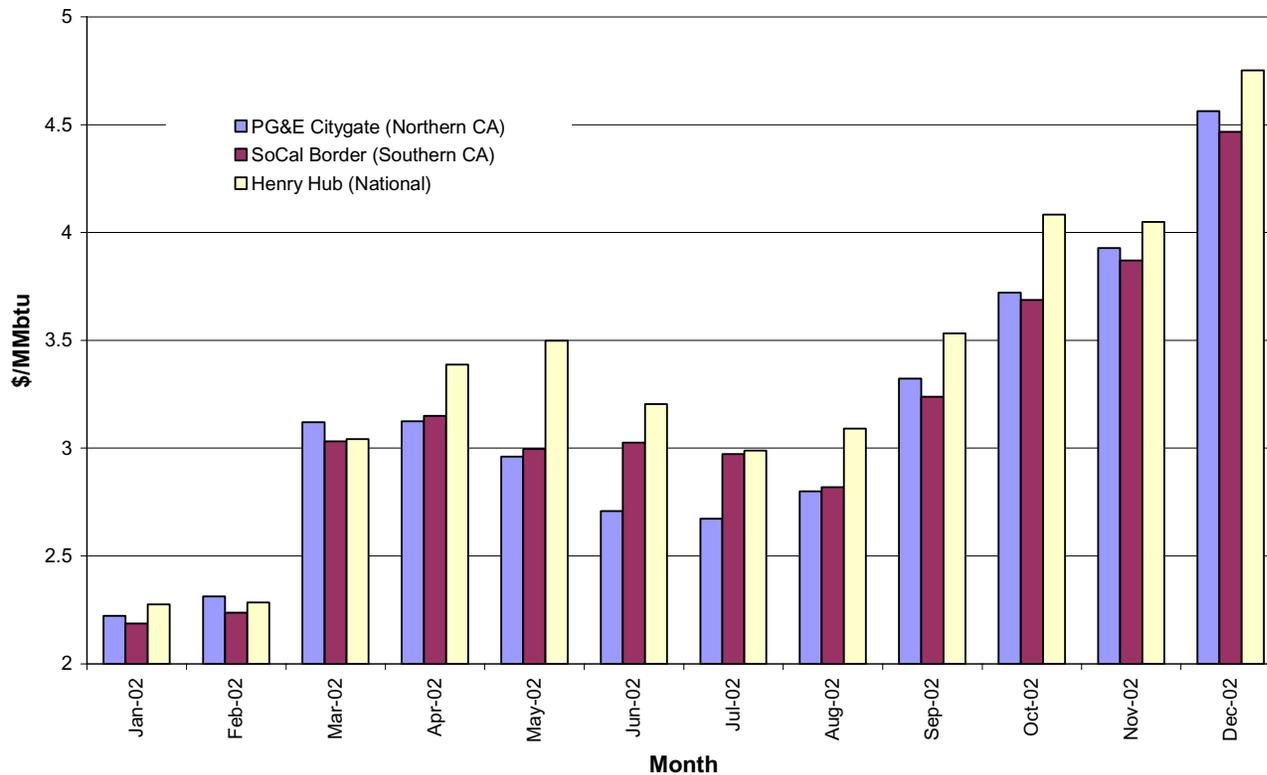
Daily Average Real-Time INC and DEC Prices in 2002





Gas prices increased steadily in 2002, Causing electricity prices to rise in step

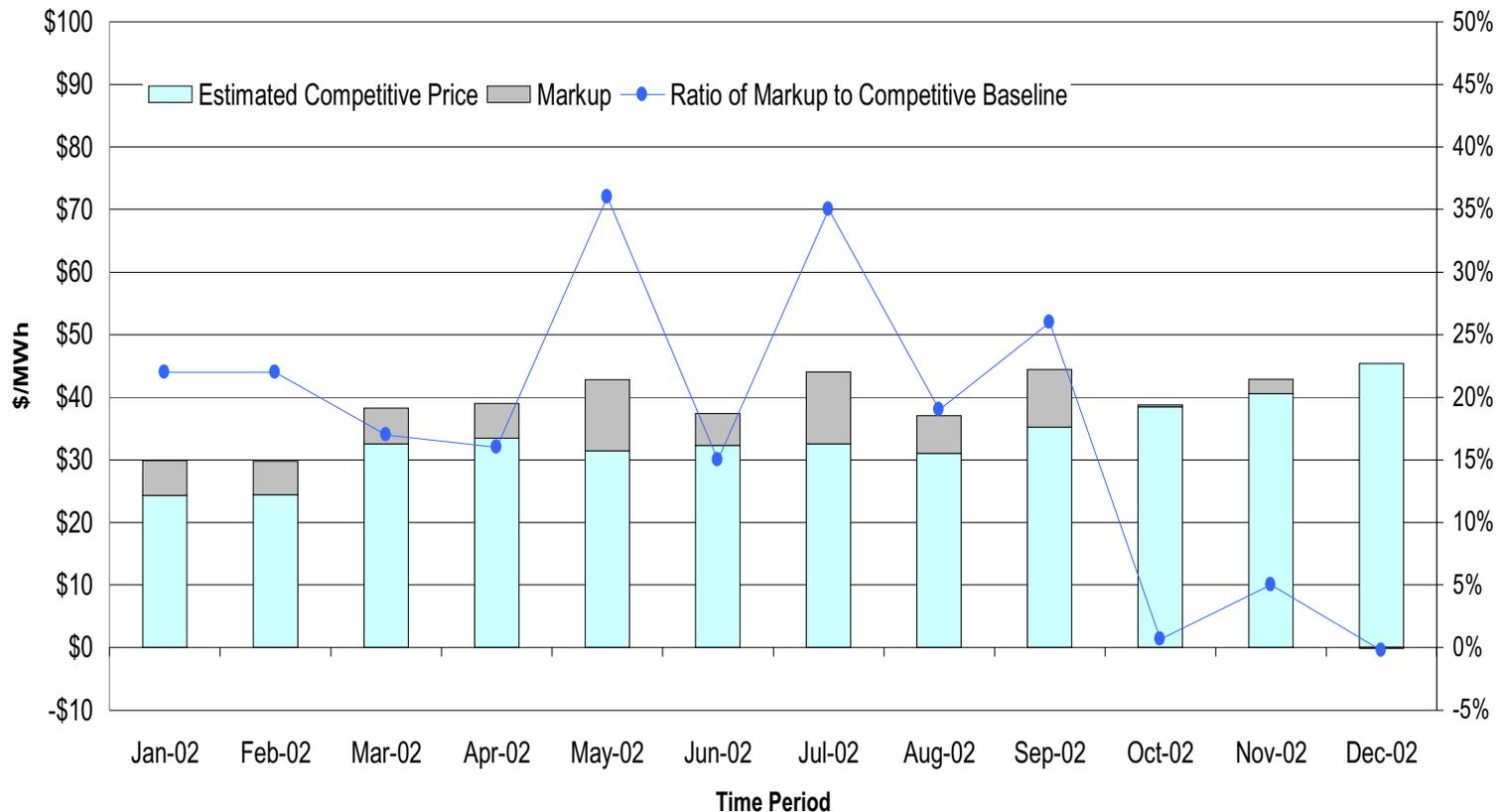
Monthly Average Prices for Natural Gas





Favorable market conditions in 2002 checked suppliers' ability to exercise market power, when compared to previous years

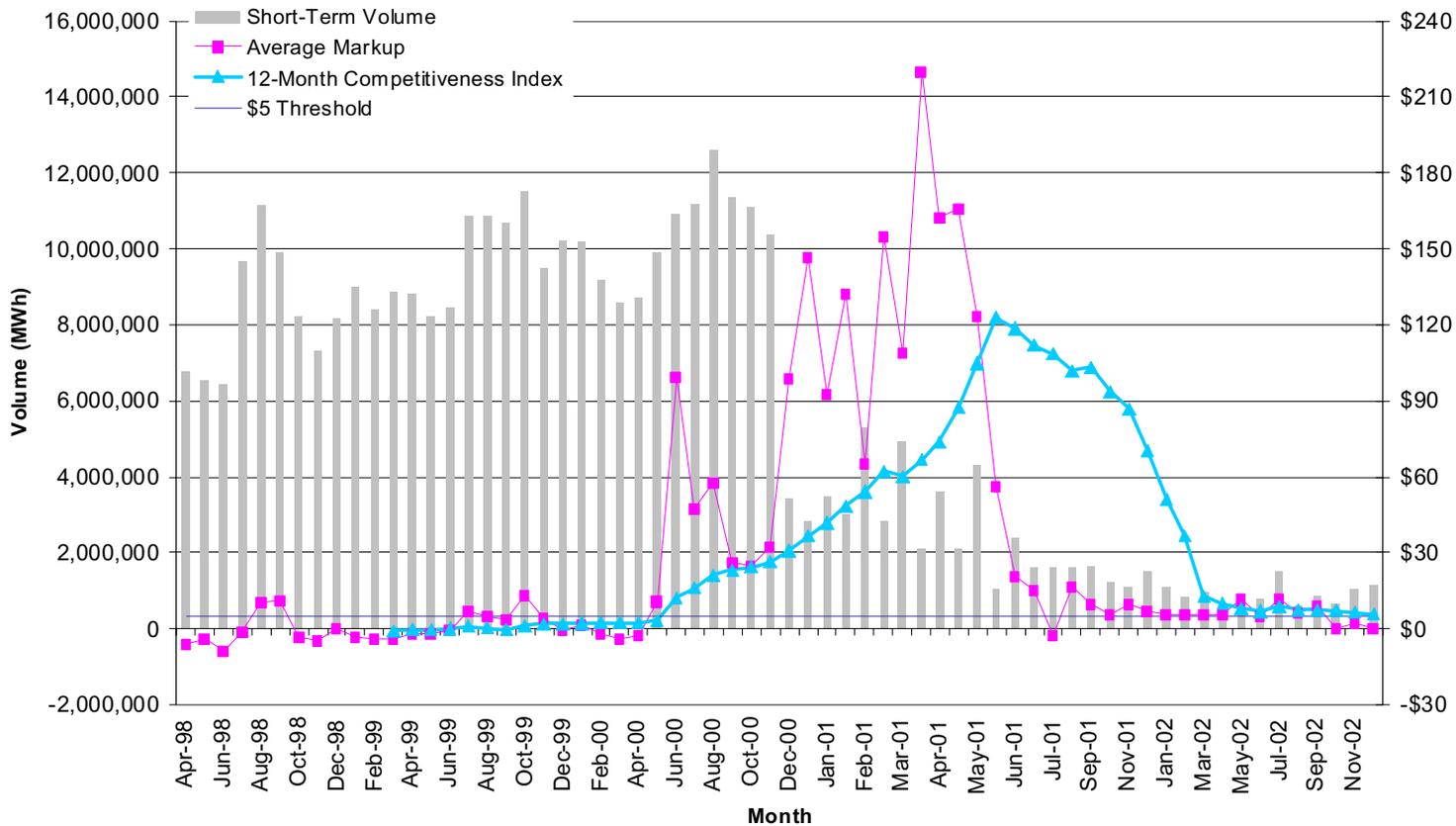
Estimated Monthly Mark –up of Prices above Competitive levels (Price-to-Cost Markup in Short-Term Energy)





Long-term market outcomes returned to workably competitive levels in 2002

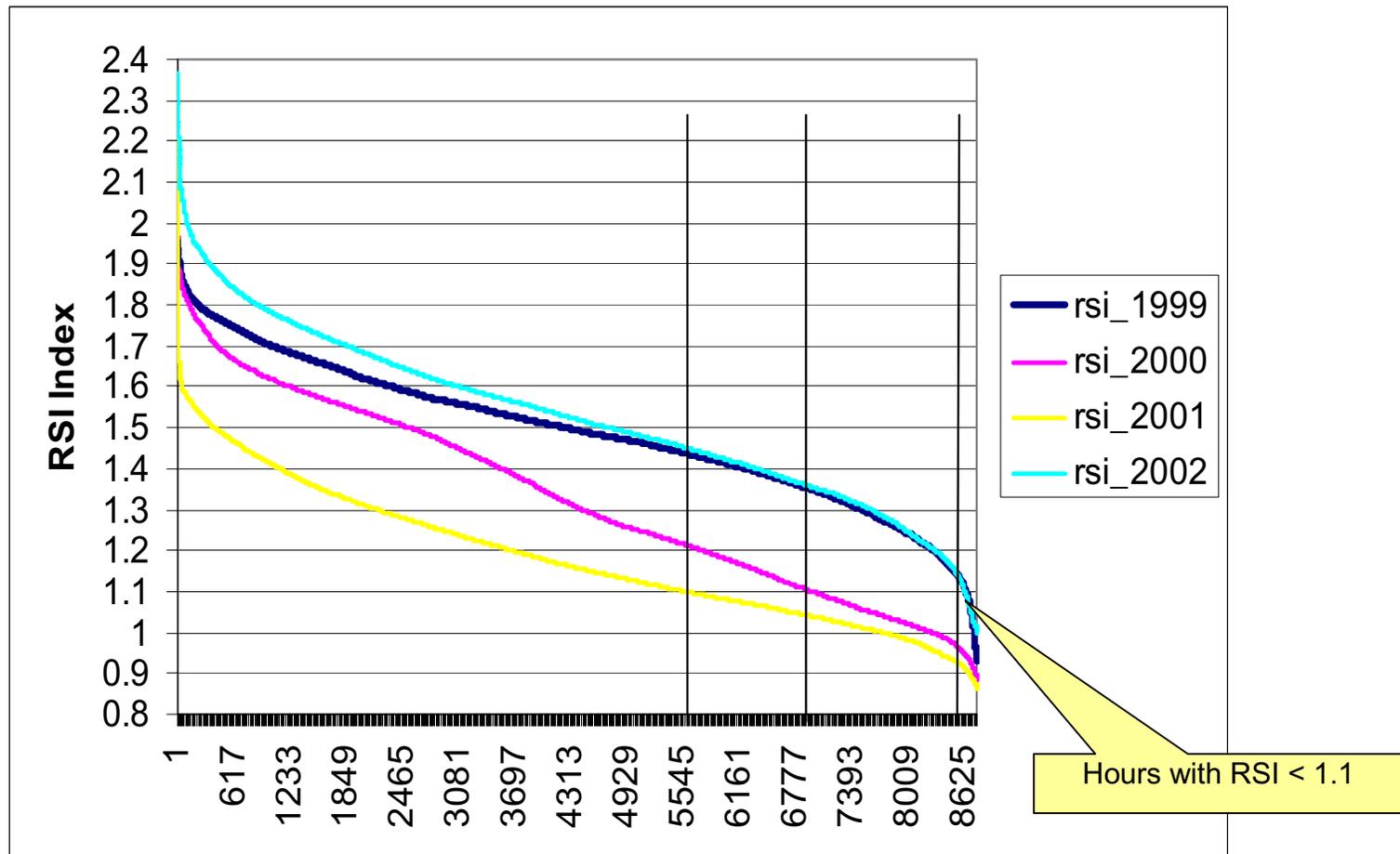
Twelve-Month Competitiveness Index through Dec-02





Return to Market Health with suppliers pivotal in fewer than 1% of hours in 2002

Residual Supply Index Duration Curves: 1999-2002
(RSI less than 1.1 indicates suppliers able to set market prices)





Market Revenues in 2002 Supported Recovery Fixed Cost of New Generation at \$72 - 77/kW-yr

Estimated Operating Revenue in ISO Energy and Ancillary Service Markets

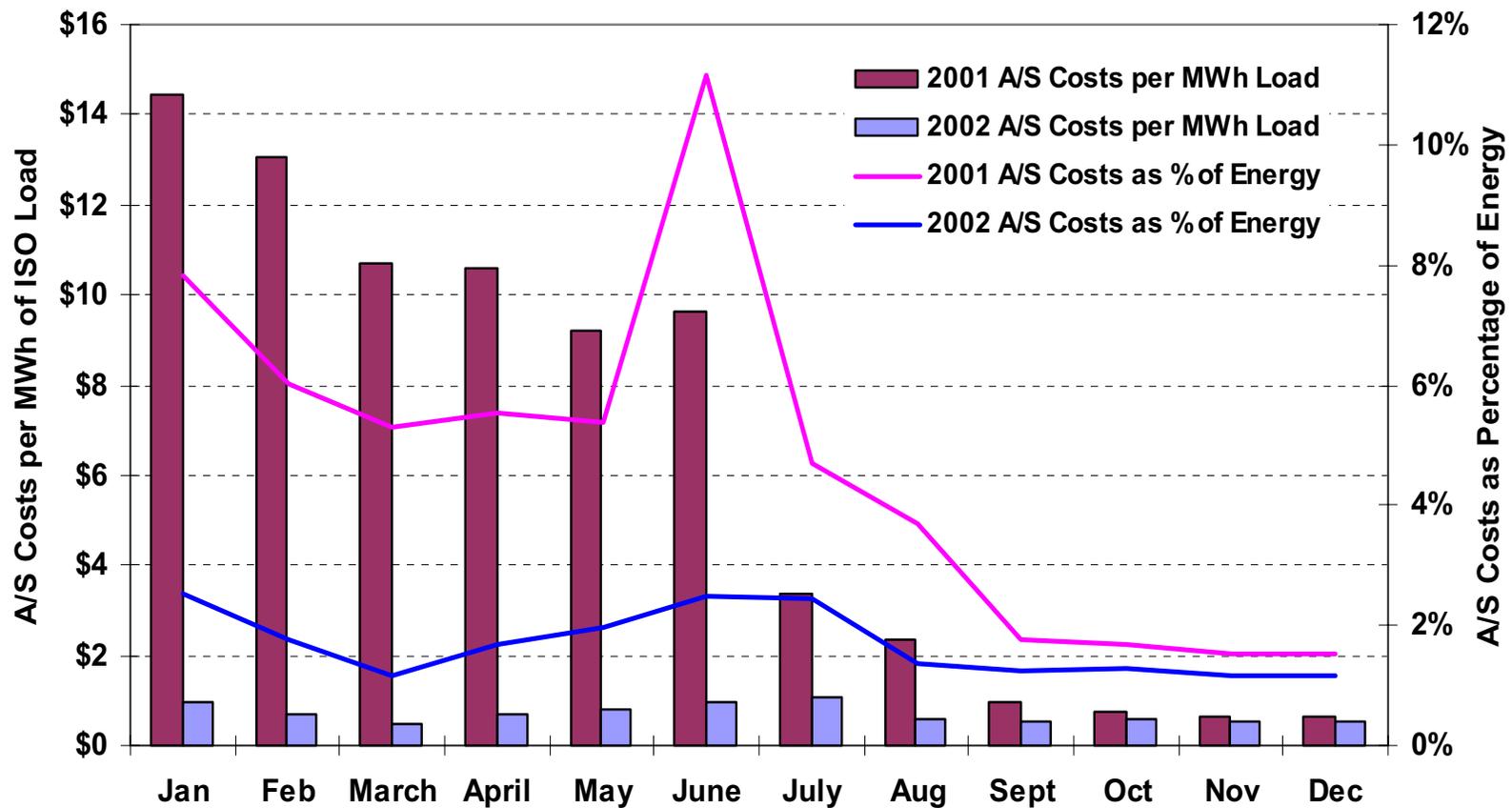
	NP15	SP15
Load Factor	61%	62%
Average Energy Revenue (\$/MWh)	\$ 40	\$ 41
Average Operating Cost (\$/MWh)	\$ 26	\$ 26
Net Energy Revenue (\$/kW/yr)	\$ 66	\$ 71
A/S Capacity Revenue (\$/kW/yr)	\$ 6	\$ 6
Total Net Revenue (\$/kW/yr)	\$ 72	\$ 77

- **Net revenue can cover the lower end of annual fixed cost estimated at \$70 to 90/kW/year**

- **Long-term contract with load is the more desirable means to ensure revenue adequacy and stability**

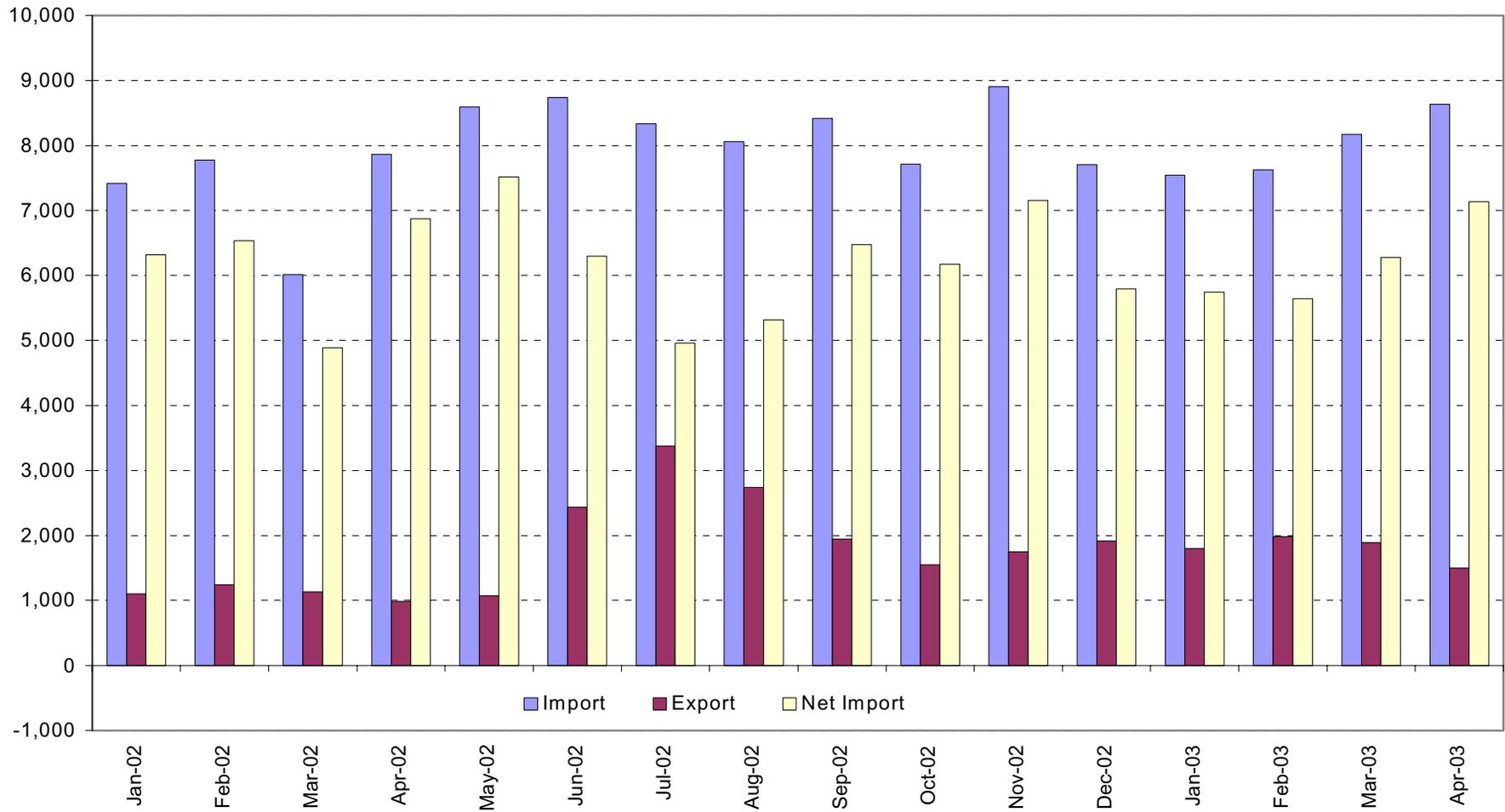


Ancillary Services Costs Down 88% in 2002 from 2001 levels
AS requirements reduced from 13 % of system load to 9.3%, largely due to less purchases of regulation service; lower prices for all AIS services





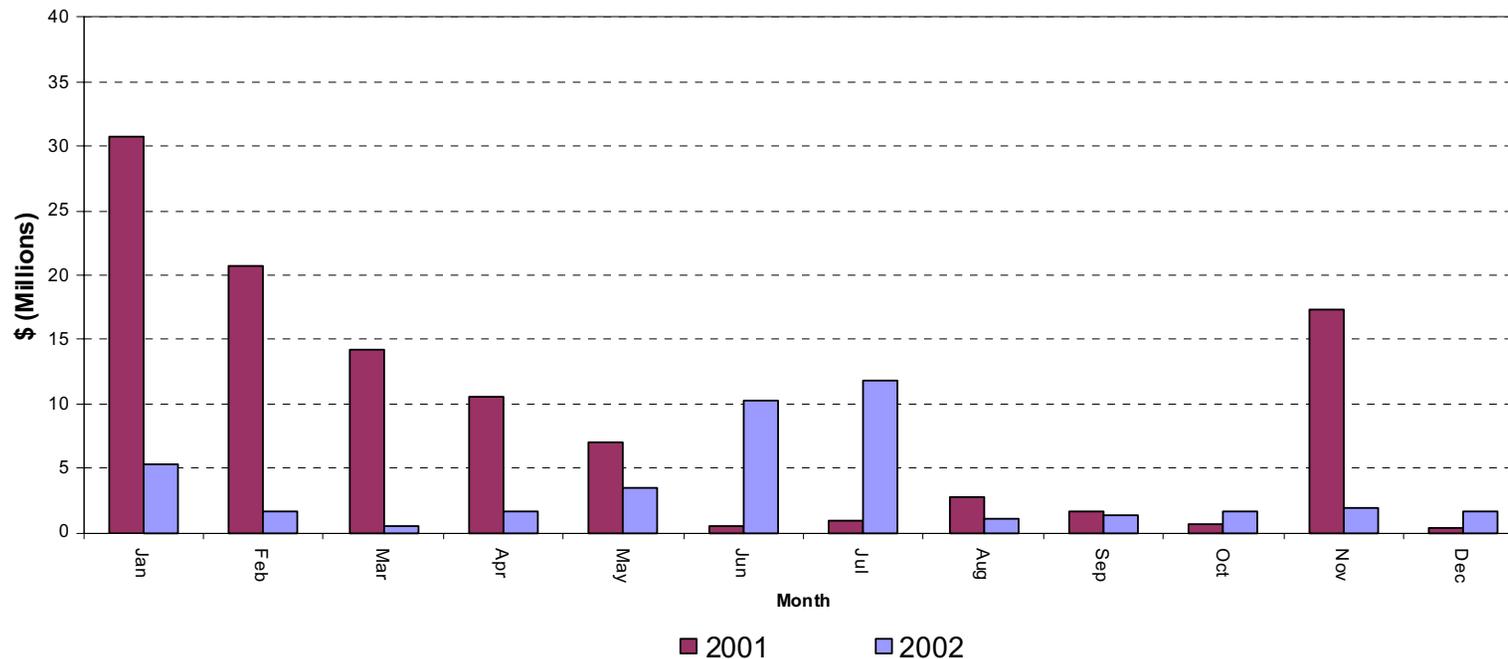
Strong import volumes into California overall ***Scheduled Imports and Exports - Monthly Averages***





Congestion costs down 61% in 2002 from 2001 levels; 2002 monthly costs significantly higher only in June and July, due to derates of key transmission lines

Monthly Total Interzonal Congestion Costs: 2002 v. 2001



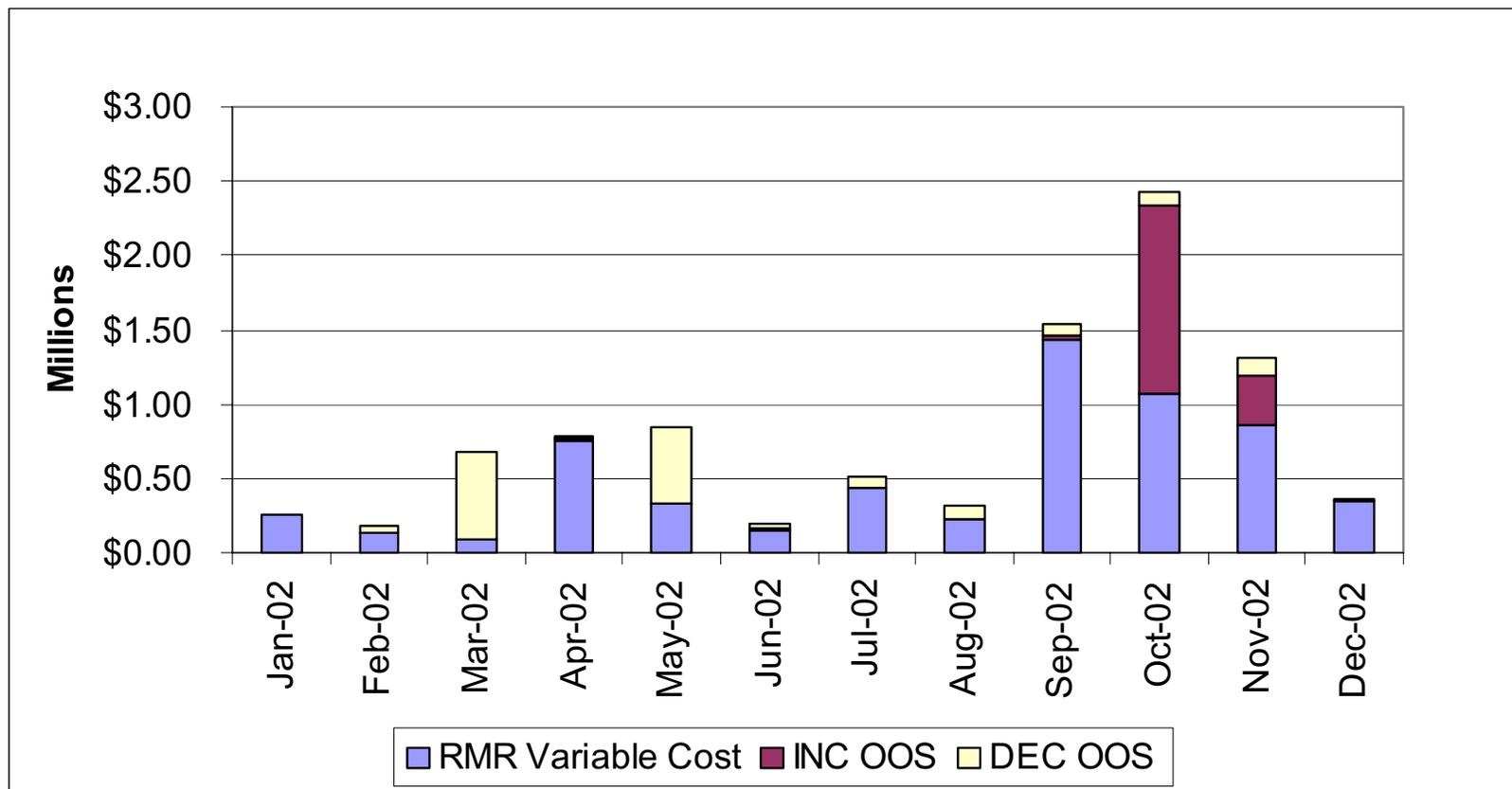


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Increased (within zone) intrazonal congestion due to new generation additions and inadequate local market power mitigation

Monthly Total Intrazonal Congestion Costs in 2002 + \$263 mil RMR Fixed Cost





Critical Market Issues Going Forward

- Lack of an effective local market power mitigation mechanism
 - Expect increased local market power with new generation
 - Current local AMP threshold of \$50 for INC and -\$30 for DEC makes mitigation ineffective
- Decline in import bids in real-time due to zero bid requirement may impact reliability
- Generators frequently decline dispatch instructions
 - Declined incremental dispatch was more than 50% in December



Going Forward: MD02 Market Redesign

- Lack of forward market mechanism to resolve intrazonal congestion
 - Intrazonal congestion managed in real time since ISO startup; susceptible to exercise of market power (DEC game, etc.)
 - MD02 Phase 2 Integrated Forward Market to simultaneously manage intrazonal and interzonal congestion in day ahead
- No formal day ahead unit-commitment process
 - Must-Offer Waiver Process is a workaround used to maintain availability of generation.
 - Integrated Forward Market set for 2004
- Slow development of price responsive demand
 - ISO markets can accommodate load-side bidding, but state has been slow in developing necessary rate design and metering systems
 - March 2003: CPUC begins 2600-customer pilot price-responsive demand study
- Other MD02 Development
 - AMP in effect since 10/30/02, but has not yet triggered mitigation
 - Real-time fully-automated economic dispatch software to be tested Summer 2003, deployed Fall 2003
 - Locational Marginal Pricing still subject to discussion but targeting fall 2004



New Demand Response Programs in California

- ISO began Participating Load Program (PLP) in 1999; mostly pump load participating; about 1 MW of non-pump load participating as ancillary services
- Mar-03: ISO formed working group to update PLP technical standards
- Mar-03: California PUC approved three pilot programs to test demand response in 2600 end-users:
 - Peak/off-peak pricing
 - Day-ahead notification of peak pricing
 - Same-day notification of peak pricing